BC HYDRO
FIRST QUARTER REPORT
FISCAL 2013

BC hydro
REGENERATION | 5

BRITISH COLUMBIA

BC HYDRO & POWER AUTHORITY
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three months ended June 30, 2012 (fiscal 2013) and should be read in conjunction with the MD&A presented in the 2012 Annual Report, the 2012 Annual Consolidated Financial Statements of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three months ended June 30, 2012.

Effective April 1, 2012, the Company changed its financial reporting framework from Canadian generally accepted accounting principles (CGAAP) to the accounting principles of International Financial Reporting Standards (IFRS) except that the Company has continued to apply regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) (collectively the "Prescribed Standards"), as prescribed by the Province of British Columbia. All financial information is expressed in Canadian dollars unless otherwise specified. For more information on the Company's transition to the Prescribed Standards, please see the "Explanation of Transition to Prescribed Standards" section of this MD&A and Notes 2 and 16 of the Unaudited Condensed Consolidated Interim Financial Statements for the three months ended June 30, 2012.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

HIGHLIGHTS

- On June 13, 2012, the British Columbia Utilities Commission (BCUC) confirmed final rate increases of 3.91 per cent and 1.44 per cent for fiscal 2013 and fiscal 2014, respectively, and approved the Deferral Account Rate Rider (DARR) of 5 per cent for both fiscal years which will reduce the energy deferral account balances over the two year period by $189 million.
- Net income after regulatory transfers for the three months ended June 30, 2012 was $53 million, $39 million below the same period in the prior fiscal year. The decrease from the prior year is due primarily to higher amortization and depreciation due to higher assets in service and higher amortization of regulatory accounts to reduce these balances.
- Usable system inflows for fiscal 2013 are forecast to be 112 per cent of average, compared with 108 per cent of average in fiscal 2012. At June 30, 2012, the combined system storage in the Company's reservoirs was 115 per cent of average compared to 102 per cent of average at June 30, 2011. As a result of the high inflows, both the Williston and Kinbasket reservoirs are spilling substantial volumes of surplus water for the summer of 2012, with the result that usable system inflows for fiscal 2013 will be significantly less than total system inflows.
- Capital expenditures for the three months ended June 30, 2012 were $435 million, $81 million above expenditures of $354 million in the same period in the prior fiscal year as the Company continues to renew its aging infrastructure and expand its facilities to meet future load growth. Transmission lines and substation replacements and enhancements, as well as the installation of smart meters and related infrastructure, accounted for the majority of the increase in capital expenditures in the current fiscal year.

	For the three months ended June 30		
(in millions)	2012	2011	Change
Net Income	$ 53	$ 92	$ (39)
Number of Domestic Customers	1,877,343	1,855,457	21,886
GWh Sold (Domestic)	13,454	11,811	1,643
Total Reservoir Storage (GWh)	26,620	23,648	2,972

(in millions)	As at June 30, 2012	As at March 31, 2012	Change
Total Assets	$ 22,214	$ 21,900	$ 314
Retained Earnings	$ 3,128	$ 3,075	$ 53
Debt to Equity	80 : 20	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

These interim statements represent the Company's initial presentation of its results and financial presentation under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS plus ASC 980, which differs from IFRS to reflect the rate-regulated environment in which the Company operates. These principles allow for the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

The transfers to or from regulatory accounts reflected in net income on the condensed consolidated interim statement of comprehensive income include: variances between forecast and actual amounts for certain revenues and costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income.

For the three months ended June 30, 2012, net transfers to regulatory accounts of $57 million were primarily due to expenditures on demand-side management programs (DSM), Site C and the Smart Metering and Infrastructure Program (SMI), increases in the provisions for asbestos and polychlorinated biphenyls (PCBs), and the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under IFRS as compared to CGAAP.

Net income after regulatory transfers for the three months ended June 30, 2012 was $53 million, $39 million below the same period in the prior fiscal year. The decrease is primarily due to higher amortization and depreciation expense due to higher assets in service and higher amortization of regulatory account balances and the lower allowed return on equity (ROE).

REVENUES

Total revenue for the three months ended June 30, 2012 was $1,058 million, a decrease of $39 million or 4 per cent compared with the same period in the prior fiscal year. Domestic revenues were comparable to the prior fiscal year while trade revenues decreased due to lower trade electricity and natural gas prices and lower gas sales volumes.

	(in millions)		*(gigawatt hours)*	
For the three months ended June 30	2012[1]	2011[1]	2012	2011
Domestic				
Residential	$ 332	$ 346	3,696	4,141
Light industrial and commercial	344	314	4,333	4,263
Large industrial	154	134	3,343	3,183
Other energy sales	59	53	2,082	224
Total Domestic Revenue Before Regulatory Transfer	889	847	13,454	11,811
Rate smoothing and load variance regulatory transfer	5	49	–	–
Total Domestic	$ 894	$ 896	13,454	11,811
Trade				
Electricity – Gross	$ 188	$ 257	10,109	8,238
Less: forward electricity purchases[2]	(40)	(71)	–	–
Electricity – Net	148	186	–	–
Gas – Gross	113	285	6,258	7,046
Less: forward gas purchases[2]	(97)	(270)	–	–
Gas – Net	16	15	–	–
Total Trade	$ 164	$ 201	16,367	15,284
Total Revenues	$ 1,058	$ 1,097	29,821	27,095

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*
[2] *Forward purchases include derivatives which are deducted from gross sales in accordance with the Prescribed Standards.*

DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the three months ended June 30, 2012 were $894 million, comparable to domestic revenues of $896 million in the same period in the prior fiscal year. Domestic revenues of $889 million before regulatory transfers were $42 million higher than in the same period in the prior fiscal year. The increase was primarily due to higher average customer rates and increased consumption by light industrial and commercial and large industrial customer classes due to increased economic activity particularly in the metal mining sector due to increased production at new and expanded mines and in the pulp and paper sectors due to higher newsprint prices. These increases were partially offset by lower consumption by residential customers primarily due to warmer weather in the current year period and lower usage. Average customer rates were higher in fiscal 2013, reflecting an average rate increase of 3.91 per cent approved by the BCUC for fiscal 2013 and a DARR of 5 per cent in fiscal 2013 compared to a DARR of 2.5 per cent in effect in fiscal 2012. Other energy sales volumes increased due to the volume (1,859 GWh) of surplus energy sold into the market as compared to the same period in the prior fiscal year when no surplus energy sales were made. Surplus energy sales were required due to current hydro conditions, but were made at very low market prices. Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA).

TRADE REVENUES

Powerex, a wholly owned subsidiary of BC Hydro, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, financial energy products, and environmental products with an expanding list of trade partners.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities help the Company balance its system by being able to import energy to meet domestic demand when there is a supply shortage in the system due to such factors as low water inflows. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the three months ended June 30, 2012 was $301 million, a decrease of $241 million compared to the same period in the prior fiscal year due to a decrease in gross electricity revenue of $69 million and a decrease in gross gas revenue of $172 million. The decrease in gross electricity revenue was primarily driven by a 34 per cent decrease in the average electricity sales price over the same period in the prior fiscal year, primarily due to lower Pacific Northwest prices as a result of high water levels and increased wind generation. The decrease in gross gas revenue was primarily driven by a 48 per cent decrease in the average gas price reflecting overall lower natural gas prices in North America following continued high shale gas production, and an 11 per cent decrease in gas sales volumes. Deducted from gross trade revenues are forward purchases, which decreased by a net $204 million compared with the same period in the prior fiscal year, primarily due to a decrease in gas prices as well as lower forward gas purchases. Forward transactions are reported on a net basis in accordance with the Prescribed Standards. Variances between actual and planned trade income are deferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the three months ended June 30, 2012, total operating expenses of $874 million were $5 million lower than in the same period in the prior fiscal year. The decrease was primarily due to lower expenditures on electricity and gas purchases and lower transmission and other charges, partially offset by higher water rentals and amortization and depreciation expenses, and higher other costs net of recoveries.

COST OF ENERGY

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs, after regulatory account transfers, for the three months ended June 30, 2012 were $371 million, $53 million or 13 per cent lower than in the same period in the prior fiscal year. The decrease was primarily due to lower trade energy purchases as a result of lower natural gas purchase volumes and prices and lower trade electricity purchase prices.

Energy costs are comprised of the following sources of supply:

	(in millions)		(gigawatt hours)		($ per MWh)	
For the three months ended June 30	**2012**	2011	**2012**	2011	**2012**[3]	2011[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 85**	$ 74	**11,600**	9,778	**$ 7.44**	$7.75
Purchases from independent power producers	**187**	163	**2,794**	2,560	**66.81**	63.49
Other electricity purchases - Domestic	**1**	11	**37**	556	**18.78**	19.80
Gas for thermal generation	**7**	8	**23**	29	**283.84**	274.22
Transmission charges and other expenses	**(33)**	3	**25**	26	**–**	–
Allocation to/from trade energy	**3**	(8)	**87**	(129)	**14.61**	39.38
Total Domestic Cost of Energy Before Regulatory Transfers	**250**	251	**14,566**	12,820	**17.14**	19.58
Domestic cost of energy regulatory transfers	**8**	16	**–**	–	**–**	–
Total Domestic	**$ 258**	$ 267	**14,566**	12,820	**$ 17.70**	$ 20.82
Trade						
Electricity - Gross	**$ 75**	$ 138	**8,215**	7,821	**$ 9.13**	$ 17.64
Less: forward electricity purchases[2]	**(40)**	(71)	**–**	–	**–**	–
Electricity - Net	**35**	67	**–**	–	**–**	–
Remarketed gas - Gross	**118**	275	**6,360**	7,091	**18.55**	38.78
Less: forward gas purchases[2]	**(97)**	(270)	**–**	–	**–**	–
Remarketed gas - Net	**21**	5	**–**	–	**–**	–
Transmission charges and other expenses	**63**	52	**–**	–	**–**	–
Allocation to/from domestic energy	**(3)**	8	**(87)**	129	**14.61**	39.38
Total Trade Cost of Energy Before Regulatory Transfers	**116**	132	**14,488**	15,041	**10.26**	13.47
Trade net margin regulatory transfer	**(3)**	25	**–**	–	**–**	–
Total Trade	**$ 113**	$ 157	**14,488**	15,041	**$ 10.03**	$ 15.12
Total Energy Costs	**$ 371**	$ 424	**29,054**	27,861	**$ 13.87**	$ 17.74

[1] *Total GWh is net of storage exchange.*
[2] *Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawattt hour (MWh) are shown at gross cost.*
[3] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $250 million for the three months ended June 30, 2012 were consistent with the same period in the prior year, with higher hydro generation volumes and increased purchase volumes from Independent Power Producers (IPPs) offset by reduced energy costs from water transactions related to the operation of Non-Treaty Storage at Mica. Higher water inflows, lack of system flexibility due to high reservoir levels, and risk of spill contributed to higher hydro generation volumes and increased purchases from IPPs also experiencing increased inflows, and resulted in lower market energy purchases for domestic load requirements and lower trade sales opportunities due to lower average electricity prices. However, an agreement with Bonneville Power Administration (BPA) to operate Non-Treaty space at Mica (effective September 2011), coupled with the renegotiation of the Non-Treaty Storage Agreement (effective April 2012), reduced energy costs by $32 million (included in Transmission charges and other expenses). Under the agreement, when the Company releases water from its portion of non-treaty storage it is entitled to the value of additional energy flowing through the U.S. Federal Columbia River, as determined by the market price of energy at that time. As at June 30, 2012, the Company has released water from its portion of non-treaty storage. Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Gross trade energy costs for the three months ended June 30, 2012 were $193 million, a decrease of $220 million compared to the same period in the prior fiscal year primarily due to a $63 million decrease in gross trade electricity purchases and a $157 million decrease in gross gas purchase costs. Trade electricity purchase costs decreased primarily due to a 48 per cent decrease in the average electricity purchase price. The decrease in the average electricity purchase price was primarily due to lower Pacific Northwest prices as a result of high water levels and increased wind generation. The decrease in gross gas purchases was due to a 52 per cent decrease in the average gas price and a 10 per cent decrease in gas purchase volumes, consistent with its decrease in gross gas revenue. Deducted from gross trade energy costs are forward purchases, which decreased by a net $204 million compared with the same period in the prior fiscal year, primarily due to a decrease in gas prices as well as lower forward gas purchases. Forward purchases are netted against forward sales within gross revenue in accordance with the Prescribed Standards. Variances between actual and planned trade income are deferred to the TIDA.

Water Inflows

Usable system inflows for fiscal 2013 are forecast to be 112 per cent of average, with inflows to the Williston Reservoir on the Peace River system at 120 per cent and the Kinbasket Reservoir on the Columbia River system at 111 per cent. Usable system inflows were approximately 108 per cent of average in fiscal 2012. For the summer of 2012, both Williston and Kinbasket reservoirs are spilling substantial volumes of surplus water as a result of the high inflows, with the result that usable system inflows for fiscal 2013 will be significantly less than total system inflows.

The Company's reservoirs have been managed such that the combined system storage in the Company's reservoirs at June 30, 2012 was 115 per cent of average (average for 1986 – 2011), with the Williston and Kinbasket reservoirs at 116 per cent and 112 per cent of average, respectively. In comparison, combined system storage at June 30, 2011 was 102 per cent of average.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post employment benefits. Personnel costs of $137 million for the three months ended June 30, 2012 were comparable to personnel costs of $138 million in the same period in the prior fiscal year. A reduction in labour costs was offset by increased expenditures on post employment benefits and fewer expenses eligible for capitalization.

MATERIALS AND EXTERNAL SERVICES

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. Expenditures on materials and external services of $145 million for the three months ended June 30, 2012 were comparable to expenditures of $144 million in the same period in the prior fiscal year.

CAPITALIZED COSTS

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. The Prescribed Standards are different than CGAAP and only allow direct overhead costs to be capitalized to property, plant and equipment, with the effect that under the Prescribed Standards there is a decrease in property, plant and equipment and a corresponding increase in operating costs. The rate impact of this increase in operating costs on transition to the Prescribed Standards is being smoothed over a ten year period through transfers to the IFRS Property, Plant and Equipment regulatory account. Capitalized costs to either property, plant and equipment or the associated regulatory accounts for the three months ended June 30, 2012 were $62 million, comparable to capitalized costs of $65 million in the same period in the prior fiscal year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory assets and liabilities. For the three months ended June 30, 2012, amortization and depreciation expense was $230 million, $32 million or 16 per cent higher than in the same period in the prior fiscal year. The increase was primarily due to higher assets in service in the current year and higher net regulatory account amortization which was primarily the result of higher recovery of energy deferral account balances due to the DARR of 5 per cent in fiscal 2013 as compared to 2.5 per cent in fiscal 2012. Regulatory account amortization in fiscal 2013 also includes the amortization of regulatory accounts established for the deferral of IFRS transition impacts, including the IFRS Pensions and Other Post Employment Benefits and IFRS Property, Plant and Equipment regulatory accounts. These increases in regulatory account amortization were partially offset by lower amortization of the DSM regulatory account balance as the amortization period in the current quarter is 15 years confirmed in the final decision on BC Hydro's fiscal 2012-2014 Amended Revenue Requirements Application (Amended RRA) as compared to the 10 years in effect during the first quarter of fiscal 2012.

GRANTS AND TAXES

As a Crown Corporation, BC Hydro is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants and taxes of $48 million for the three months ended June 30, 2012 were consistent with the same period in the prior fiscal year.

OTHER COSTS (RECOVERIES)

Other costs (recoveries) primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. Total other costs net of recoveries of $5 million were $11 million higher than in the same period in the prior fiscal year due to higher losses incurred on asset disposals and retirements and lower cost recoveries in the current period.

FINANCE CHARGES

Finance charges after net regulatory transfers for the three months ended June 30, 2012 of $131 million were $5 million or 4 per cent higher than in the same period in the prior fiscal year. The increase is primarily due to a higher volume of long-term debt issues partially offset by higher capitalized interest during construction.

REGULATORY ACCOUNT TRANSFERS

The Company has established various regulatory accounts with the approval of the BCUC. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

Net regulatory account transfers are comprised of the following:

For the three months ended June 30 (in millions)		2012
Variances between forecast and actual costs		
Energy deferral accounts	$	(5)
Finance charges		(6)
Other		(5)
		(16)
Deferral of costs for future recovery in rates		
Demand Side Management		28
Site C		15
Smart Metering and Infrastructure		19
Environmental Provisions		26
First Nations		5
IFRS Property, Plant and Equipment		49
Other		2
		144
Rate Smoothing Account		(9)
Amortization of regulatory accounts		(74)
Interest on regulatory accounts		12
Net change in regulatory accounts	$	57

For the three months ended June 30, 2012, net additions after amortization to the Company's regulatory accounts were $57 million. The net asset balance in the regulatory asset and liability accounts as at June 30, 2012 was an asset of $4,092 million compared to an asset of $4,035 million at March 31, 2012.

Additions to the regulatory accounts during the three months ended June 30, 2012 included:

- Expenditures on DSM projects, which support energy conservation, on the Site C project and on SMI reflecting the project being in active implementation phase in the first three months of fiscal 2013.
- Transfers to the Environmental Provisions regulatory account reflecting increases required to provisions for asbestos and PCB contamination.
- Transfers to the IFRS Property, Plant and Equipment regulatory account are for the smoothing of the rate impact of overhead costs eligible for capitalization under CGAAP but not eligible under IFRS as they are not considered directly attributable to the construction of capital assets.

Decreases in the regulatory accounts during the period included:

- Transfers from the Rate Smoothing regulatory account smooth the rate increases over the three years covered by the Amended RRA. The balance of the Rate Smoothing regulatory account will be fully drawn down at the conclusion of the three year period.
- Transfers from the energy deferral accounts due to favourable variances between forecast and actual domestic energy costs and trade income.

ACCOUNTING CHANGES

EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

On April 1, 2012, the Company adopted the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). The Company prepared its condensed consolidated interim financial statements for the three month period ended June 30, 2012 in accordance with IFRS, except that in accordance with the aforementioned legislation, it continues to apply regulatory accounting in accordance with the ASC 980. The application of ASC 980 results in the Company recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the BCUC for inclusion in future customer rates. In accordance with IFRS, such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The comparative periods included in these financial statements have been restated to the Prescribed Standards. The Company's previously issued interim and annual financial statements prior to and including the year ended March 31, 2012 were prepared in accordance with CGAAP.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, BC Hydro is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No Payment has been accrued as at June 30, 2012 for fiscal 2013 as BC Hydro's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At June 30, 2012, Powerex was owed US $265 million (CDN $270 million) plus interest by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 20, 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties. It is expected that the receivables owed to Powerex will be offset against the market-wide refund that Powerex is required to pay.

The Company has elected not to report information regarding provisions as this information could prejudice the Company's position in ongoing litigation.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve an annual rate of return on deemed equity (ROE). The annual rate of return is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. This is in accordance with Heritage Special Direction No. HC2. The allowed rate of return for fiscal 2013 is 11.73 per cent, and is lower than the prior year's allowed rate of 14.38 per cent due to changes to the effective tax rate for FortisBC Energy Inc. upon which BC Hydro's rate of return is based and the elimination of the return on equity adder that was in place in fiscal 2012.

Heritage Special Direction No. HC2 defines equity for rate-setting purposes (Deemed Equity) as 30 per cent of BC Hydro's rate base, which is comprised of a working capital allowance, assets in service (excluding leased assets), and DSM expenditures, less contributions in aid of construction and Columbia River Treaty contributions.

AMENDED FISCAL 2012-2014 REVENUE REQUIREMENTS APPLICATION

On May 22, 2012, the Province issued Direction No. 3 which directs the BCUC to set rates at 8 per cent, 3.91 per cent and 1.44 per cent for fiscal 2012, 2013, and 2014, respectively, and set the DARR at 5 per cent for fiscal 2013 and 2014. By maintaining the DARR at 5 per cent, an additional $189 million will be applied to reduce the energy deferral account balances over fiscal 2013 and 2014. The allowed ROE for fiscal 2013 and 2014 was reduced from 12.75 per cent in each year to 11.73 per cent and 11.84 per cent, respectively, which reflects changes to Fortis's ROE due to a lower income tax rate which is used to calculate BC Hydro's ROE. The Province also amended the Heritage Special Direction No. 2 to remove the $200 million cap on Powerex income allowing ratepayers to benefit from all of Powerex's income. Any losses incurred by Powerex will not impact ratepayers.

On June 13, 2012, the BCUC issued Order No. G-77-12 incorporating the requirements of Direction No. 3 and setting BC Hydro's rates for fiscal 2013 and 2014 and bringing to a close the regulatory preceding.

DAWSON CREEK/CHETWYND AREA TRANSMISSION UPGRADE PROJECT

On July 11, 2011, BC Hydro filed an application with the BCUC for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission Upgrade Project. This project proposes to address electricity supply constraints in the southern Peace region of the province and meet significant forecasted load growth in that region attributable to the development of the Montney natural gas field. The project involves the construction of a new substation, a new 230 kV transmission line and the expansion of an existing substation at an estimated cost of approximately $220 to $260 million. If approved by the BCUC, the project is expected to be in service by April 2014. The review of the application was suspended on November 30, 2011 to allow BC Hydro time to collaborate with government in addressing policy issues raised by the BCUC and interveners that were not included in the CPCN application. On April 11, 2012, the BCUC lifted the suspension, thereby reactivating the proceeding. On May 7, 2012, the BCUC narrowed the scope of the hearing to exclude these broader policy and rate design issues and established a regulatory review process for the remainder of the hearing that will conclude in early August, with a Decision expected in October 2012.

JOHN HART GENERATING STATION REPLACEMENT PROJECT

On May 25, 2012, BC Hydro filed an application for a CPCN for the John Hart Generating Station Replacement Project. This project involves replacing the existing three 1.8-kilometre long penstocks with a 2.1-kilometre tunnel through bedrock, constructing a replacement generating station beside the existing station, constructing a replacement water intake at the John Hart Spillway Dam, and building a new water bypass facility. The projected cost is $1 billion to $1.2 billion; if approved by BCUC, the first replacement generating unit is expected to be in service by 2017 with project completion by the end of 2018. On July 27, 2012, the Company filed the responses to over 700 Information Requests from the BCUC and Intervenors. A second round of Information Requests is due from the BCUC and Intervenors on August 10, 2012. A Procedural Conference is set for September 17, 2012 to determine the next steps in the regulatory proceeding.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the three months ended June 30, 2012 was $38 million, compared with cash flow provided by operating activities of $83 million in the same period in the prior fiscal year. The decrease was primarily due to lower net income before regulatory transfers and before amortization, higher interest paid, and unrealized gains related to mark to market adjustments in the current fiscal year compared to unrealized losses related to mark to market adjustments in the prior year.

The long-term debt balance net of sinking funds at June 30, 2012 was $13.4 billion, compared with $12.8 billion at March 31, 2012. The increase was mainly a result of net long-term bond issues totaling $655 million ($578 million par value) and a net foreign exchange revaluation loss of $22 million on US dollar denominated bonds and sinking funds. This increase was partially offset by a decrease in revolving borrowings of $71 million and a decrease of $11 million in debt due to fair value hedge accounting.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended June 30	
(in millions)	2012	2011
Distribution system improvements and expansion	$ 76	$ 71
Generation replacements and expansion	91	106
Transmission lines and substation replacements & expansion	145	95
Smart Metering and Infrastructure program	97	17
General, including computers, vehicles and building improvements	26	65
Total Property, Plant and Equipment Expenditures	$ 435	$ 354

Total property, plant and equipment expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Interim Statement of Cash Flows due to the effect of accruals related to these expenditures.

Distribution capital expenditures for the first quarter ended June 30, 2012 were comparable to the same period in the prior fiscal year.

Generation capital expenditures for the first quarter ended June 30, 2012 decreased by $15 million compared with the same period in the prior fiscal year. The decrease was primarily due to lower spending in fiscal 2013 on the Fort Nelson resource smart upgrade as it was put into service in the fourth quarter of fiscal 2012. This decrease was slightly offset by higher spending in fiscal 2013 on the Ruskin dam and powerhouse upgrade and the Mica units 5 and 6 project.

Transmission lines and substations capital expenditures for the first quarter ended June 30, 2012 increased by $50 million compared with the same period in the prior fiscal year. The increase was primarily due to higher spending in fiscal 2013 on the Northwest transmission line project, the Columbia Valley transmission project, the Interior to Lower Mainland project and the Dawson Creek/Chetwynd Area transmission project.

SMI capital expenditures for the first quarter ended June 30, 2012 increased by $80 million compared with the same period in the prior fiscal year as the project is well into the implementation phase in fiscal 2013 with the installation of meters, telecom and information technology infrastructure all in progress.

General capital expenditures for the first quarter ended June 30, 2012 decreased by $39 million compared with the same period in the prior year. The decrease was primarily due to higher spending in fiscal 2012 on field building upgrades and replacements and increased vehicle expenditures.

RISK MANAGEMENT

The Company is exposed to numerous risks, which can be broadly classified as either "Operating" or "Strategic" in nature. Operating risks arise from the construction, ownership, operation and decommissioning of the company's assets. The consequences of operating risks include safety, environmental, financial, reliability and reputational impacts and can range in scale from minor to catastrophic. Significant strategic risks include both long term and short term load/resource balance, exposure to commodity and financial market prices, stakeholder relationships and access to adequate funding. The potential consequences of these risks are similar to those of operating risks and can vary from minor to significant.

The Company strives to manage all the risks it faces on a cost effective basis, taking into account the potential reward to be gained in return for acceptance of the risk. The Company also strives to manage significant risks in conformity with the provisions of the international standard ISO 31000, "Risk Management – Principles and Guidelines", or in conformity with other externally recognized standards appropriate to the risk being managed.

The Board of Directors is accountable for all risks incurred by the Company and its subsidiaries. Authority for risk management is delegated to the Chief Executive Officer. The Chief Risk Officer is charged with the development of the enterprise risk management framework across all of the Company, which provides the basis for consistent application of risk management practices. The Board of Directors and management regularly review and discuss the risk profile of the organization and consider the nature and amount of risk incurred in the pursuit of the organization's objectives.

There were no changes in the significant risks to the Company's business during the three months ended June 30, 2012 from those discussed in the Management Discussion and Analysis presented in the Annual Report for the year ended March 31, 2012, with the exception of the following:

Load/Energy Resource Balance

System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 was 8 per cent above average. Due to a high snowpack at the beginning of fiscal 2013, and then very heavy rainfall across the province in June, the system inflow energy for fiscal 2013 is now forecast to be 12 per cent above normal. Net market sales for fiscal 2013 are now forecast to be 7,200 GWh (equivalent to 13 per cent of our domestic load). Several factors constrain the Company's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even when the system has annual net energy sales, some electricity purchases are likely required during constrained periods of the year (e.g. late fall, winter, early spring), while electricity sales may be unavoidable during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk.

Electricity demand is generally increasing as B.C.'s population increases. However, this demand can be variable. Demand for the large industrial customers is particularly uncertain due to variability in export markets and world commodity prices, and the potential for major new loads such as Liquefied Natural Gas (LNG). The Company regularly models the projected supply-demand balance of the system over the short term to plan optimum system operations and over the medium term in an effort to cost-effectively meet demand.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2012 forecasts net income for fiscal 2013 at $566 million. The Service Plan included a 3.91 per cent interim rate increase for fiscal 2013.

Subsequent to the Service Plan, the Government issued Direction No. 3 to the BCUC which included, among other things, the setting of the interim rate increase in fiscal 2013 of 3.91 per cent as final and lowering the allowed rate of return on deemed equity for fiscal 2013 from 12.75 per cent to 11.73 per cent. This results in a forecast net income of $520 million for fiscal 2013.

The Company's results can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather, temperatures, interest rates and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The updated forecast assumes higher than average water inflows (110 per cent of average) for fiscal 2013, customer load of 51,779 GWh, average market energy prices of CDN $25.90/MWh, short-term interest rates of 1.05 per cent and a U.S. dollar exchange rate of US$0.9839.

The Company filed an updated forecast with the Province in September 2012. The updated net income forecast for fiscal 2013 is unchanged at $520 million. The significant changes from the Service Plan (adjusted for the BCUC decision on the Amended RRA) for fiscal 2013 include:

- A reduction of 1,748 GWh in customer sales load of 51,779 GWh from the Service Plan. This decrease is mainly due to a reduction in load in the residential and large industrial and commercial sectors. Residential has decreased mainly due to lower forecast customer growth as a result of lower housing starts. The large industrial and commercial sector has decreased largely a result of a slower than expected economic recovery especially in the pulp and paper sector.
- A decrease in the forecast cost of energy resulting mainly from the impact of higher water inflows which is at 110 per cent of average. As a result, hydro-generation is forecast to increase and displace higher priced market energy purchases and increase surplus sales. A decrease in the volume of energy supply required due to the decrease in customer load also contributes to the decrease in energy costs.

The impact of the changes above flow through BCUC approved regulatory accounts for inclusion in future rates and therefore has no impact on net income in fiscal 2013.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended June 30* 2012	2011
Revenues		
Domestic	$ 894	$ 896
Trade	164	201
	1,058	1,097
Expenses		
Operating Costs (Note 4)	874	879
Finance Charges (Note 5)	131	126
Net Income	$ 53	$ 92
Other Comprehensive Income (Loss):		
Effective portion of changes in fair value of derivatives designated as cash flow hedges	5	(11)
Reclassification to income of gain (loss) on derivatives designated as cash flow hedges	(15)	8
Foreign currency translation gains (losses)	2	(3)
Other Comprehensive Income (Loss)	(8)	(6)
Total Comprehensive Income	$ 45	$ 86

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)	As at June 30 2012	As at March 31 2012	As at April 1 2011
ASSETS			
Current Assets			
Cash and cash equivalents	$ 7	$ 12	$ 27
Accounts receivable and accrued revenue	590	595	569
Inventories (Note 7)	160	142	126
Prepaid expenses	164	147	156
Current portion of derivative financial instrument assets	93	140	198
	1,014	1,036	1,076
Non-Current Assets			
Property, plant and equipment (Note 8)	16,265	15,991	15,019
Intangible assets	412	412	335
Regulatory assets (Note 9)	4,378	4,314	3,419
Sinking funds	109	105	97
Derivative financial instrument assets	36	42	27
	21,200	20,864	18,897
	$ 22,214	$ 21,900	$ 19,973
LIABILITIES AND EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities (Notes 11 and 13)	$ 1,084	$ 1,431	$ 1,610
Current portion of long-term debt (Note 10)	3,190	2,896	2,803
Current portion of derivative financial instrument liabilities	160	123	165
	4,434	4,450	4,578
Non-Current Liabilities			
Long-term debt (Note 10)	10,355	10,054	8,909
Regulatory liabilities (Note 9)	286	279	275
Derivative financial instrument liabilities, long-term	92	189	212
Contributions in aid of construction	1,162	1,106	1,012
Post employment benefits	1,187	1,182	845
Other long-term liabilities (Note 13)	1,434	1,421	1,261
	14,516	14,231	12,514
Shareholder's Equity			
Contributed surplus	60	60	60
Retained earnings	3,128	3,075	2,747
Accumulated other comprehensive income	76	84	74
	3,264	3,219	2,881
	$ 22,214	$ 21,900	$ 19,973

Commitments and Contingencies (Note 14)

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Approved on Behalf of the Board:

Dan Doyle
Chairman

Tracey L. McVicar
Chair, Audit & Finance Committee

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains/(Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2011	$ -	$ 74	$ 74	$ 60	$ 2,747	$ 2,881
Payment to the Province	-	-	-	-	-	-
Comprehensive Income (Loss)	(3)	(3)	(6)	-	92	86
Balance, June 30, 2011	$ (3)	$ 71	$ 68	$ 60	$ 2,839	$ 2,967
Balance, April 1, 2012	$ 21	$ 63	$ 84	$ 60	$ 3,075	$ 3,219
Payment to the Province	-	-	-	-	-	-
Comprehensive Income (Loss)	2	(10)	(8)	-	53	45
Balance, June 30, 2012	$ 23	$ 53	$ 76	$ 60	$ 3,128	$ 3,264

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the three months ended June 30* 2012	2011
Operating Activities		
Net income	$ 53	$ 92
Regulatory account transfers	(134)	(116)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 9)	74	33
Amortization and depreciation expense	153	146
Unrealized gains on mark-to-market	(12)	6
Interest accrual	150	147
Other items	13	52
	297	360
Changes in:		
Accounts receivable and accrued revenue	9	1
Prepaid expenses	(17)	(40)
Inventories	(17)	(23)
Accounts payable and accrued liabilities	(82)	(54)
Contributions in aid of construction	64	27
	(43)	(89)
Interest paid	(216)	(189)
Interest received	-	1
Cash provided by operating activities	38	83
Investing Activities		
Property, plant and equipment and intangible asset expenditures	(393)	(396)
Cash used in investing activities	(393)	(396)
Financing Activities		
Long-term debt issued	657	987
Receipt of revolving borrowings	1,532	1,017
Repayment of revolving borrowings	(1,603)	(1,235)
Payment to the Province (Note 11)	(230)	(463)
Other items	(6)	(13)
Cash provided by financing activities	350	293
Decrease in cash and cash equivalents	(5)	(20)
Cash and cash equivalents, beginning of period	12	27
Cash and cash equivalents, end of period	$ 7	$ 7

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The condensed consolidated interim financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries including Powerex Corp. (Powerex), Powertech Labs Inc., BCH Services Asset Corp., and Columbia Hydro Constructors Ltd., (collectively with BC Hydro, "the Company") including BC Hydro's one third interest in the Waneta Dam and generating facility, a joint operation. All intercompany transactions and balances are eliminated upon consolidation.

The Company accounts for its one third interest in the Waneta Dam and generating facility as a joint operation. The consolidated financial statements includes BC Hydro's proportionate share of the Waneta Dam and generating facility and BC Hydro's liabilities and expenses, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. and its revenue from the sale of the output in relation to the Waneta Dam and generating facility.

NOTE 2: BASIS OF PRESENTATION

(a) Basis of Accounting

These condensed consolidated interim financial statements have been prepared in accordance with significant accounting policies as set out in Note 3. These policies have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare its consolidated financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS) except that BC Hydro is to continue to apply regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations* (collectively the "Prescribed Standards"). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred.

BC Hydro's accounting policies with respect to its regulatory accounts are disclosed in Note 3(a) and the impact of the application of ASC 980 on these condensed consolidated interim financial statements is described in Note 9. The accounting policies adopted under the Prescribed Standards have been applied consistently to all periods presented in these financial statements and by all subsidiaries of BC Hydro.

As these interim statements represent BC Hydro's initial presentation of its results and financial presentation under the Prescribed Standards, they have been prepared by management in accordance with the principles of IAS 34, *Interim Financial Reporting* and IFRS 1, *First Time Adoption of IFRS* and do not include all of the disclosure requirements for annual financial statements. In prior years, these financial statements were prepared in compliance with Canadian Generally Accepted Accounting Principles (CGAAP). In preparing these interim statements, management has amended certain accounting methods previously applied in the CGAAP consolidated financial statements to comply with the Prescribed Standards. The comparative figures for the prior year were restated to reflect these amendments. The change in accounting policies from CGAAP to the Prescribed Standards includes the application of certain exemptions that were adopted on transition (see Note 16). An explanation of how the transition to the Prescribed Standards has affected the reported financial position, financial performance and cash flows of BC Hydro is also provided in Note 16.

These condensed consolidated interim financial statements were approved by the Board of Directors on August 15, 2012.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial instruments that are accounted for according to the financial instrument categories as defined in Note 3(j).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex Corporation (Powerex), is the Canadian dollar. Powerex's functional currency is the U.S. dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million unless otherwise stated.

(d) Key Assumptions and Significant Judgements

The preparation of financial statements in conformity with the Prescribed Standards requires management to make judgements, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgements, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about significant areas of judgements, estimates and assumptions in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is as follows:

(i) Retirement Benefit Obligation

BC Hydro provides a defined benefit statutory pension plan for its employees which is accounted for in accordance with IAS 19, *Employee Benefits*. Actuarial valuations are based on key assumptions which include employee turnover, mortality rates, discount rates, earnings increases and expected rate of return on retirement plan assets. Judgement is exercised in determining these assumptions. The assumptions adopted are based on prior experience, market conditions and advice of plan actuaries. Future results are impacted by these assumptions including the accrued benefit obligation and current service cost.

(ii) Provisions and Contingencies

Management is required to make judgements to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*. IAS 37 requires that a provision be recognized where there is a present obligation as a result of a past event, it is probable that transfer of economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Key judgements are whether a present obligation exists and the probability of an outflow being required to settle that obligation.

Key assumptions in measuring recorded provisions include the timing and amount of future payments and the discount rate applied in valuing the provision.

The Company and its subsidiary Powerex, are currently defending certain lawsuits where management must make judgements, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management has obtained the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

(iii) Financial Instruments

The Company enters into financial instrument arrangements which require management to make judgements to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*. Key judgements are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Valuation techniques are used in measuring the fair value of financial instruments when active market quotes are not available. Valuation of the Company's financial instruments is based in part on forward prices which are volatile and therefore the actual realized value may differ from management's estimates.

(iv) Leases

The Company enters into long-term energy purchase agreements that may be considered or contain a lease. In making this determination, judgement is required to determine whether the fulfillment of an arrangement is dependent on the use of a specific asset, and whether the arrangement conveys a right to use the asset. For those arrangements considered to be, or contain, an embedded lease, further judgement is required to determine whether to account for the agreement as either a finance or operating lease by assessing whether substantially all of the significant risks and rewards of ownership are transferred to the Company or remain with the counterparty to the agreement. The measurement of finance leases requires the estimate of the amount and timing of future cash flows and the determination of an appropriate discount rate.

NOTE 3: SIGNIFICANT ACCOUNTING POLICIES

(a) Rate Regulation

BC Hydro is regulated by the BCUC and both entities are subject to directives and directions issued by the Province. BC Hydro operates under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies the principles of ASC 980, which differs from IFRS, to reflect the impacts of the rate regulated environment in which BC Hydro operates (see Note 9). Generally, this results in the deferral and amortization of costs and recoveries to allow for adjustment of future customer rates. In the absence of rate regulation, these amounts would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. BC Hydro capitalizes as a regulatory asset all or part of an incurred cost that would otherwise be charged to expense or other comprehensive income if it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes and the future rates and revenue approved by the BCUC will permit recovery of that incurred cost. Regulatory liabilities are recognized for certain gains or other reductions of net allowable costs for adjustment of future rates as determined by the BCUC.

These accounting policies support BC Hydro's rate regulation and regulatory accounts have been established through ongoing application to, and approval by, the BCUC. When a regulatory account has been or will be applied for and, in management's estimate, acceptance of deferral treatment by the BCUC is considered probable, BC Hydro defers such costs in advance of a final decision of the BCUC. If the BCUC subsequently denies the application for regulatory treatment, the deferred amount is recognized immediately in comprehensive income.

(b) Revenue

Domestic revenues comprise sales to customers within the province of British Columbia and sales of firm energy outside the province under long-term contracts that are reflected in BC Hydro's domestic load requirements. Other sales outside the province are classified as trade.

Revenue is recognized at the time energy is delivered to BC Hydro's customers, the amount of revenue can be measured reliably and collection is reasonably assured. Revenue is determined on the basis of billing cycles and also includes accruals for electricity deliveries not yet billed.

Energy trading contracts that meet the definition of a financial or non-financial derivative are accounted for at fair value whereby any realized gains and losses and unrealized changes in the fair value are recognized in trade revenues in the period the change occurred.

Energy trading and other contracts which do not meet the definition of a derivative are accounted for on an accrual basis whereby the realized gains and losses are recognized as revenue as the contracts are settled. Such contracts are considered to be settled when, for the sale of products, the significant risks and rewards of ownership transfer to the buyer, and for the sale of services, those services are rendered.

(c) Finance Income and Charges

Finance income comprises income earned on sinking fund investments held for the redemption of long-term debt, the expected return on defined benefit plan assets, foreign exchange gains and realized hedging instruments gains that are recognized in the statement of comprehensive income, excluding energy trading contracts.

Finance charges comprise interest expense on borrowings, accretion expense on asset retirement obligations, interest on defined benefit obligations, interest on finance lease liabilities, foreign exchange losses and realized hedging instruments losses that are recognized in the statement of comprehensive income. All borrowing costs are recognized using the effective interest rate method.

Finance costs exclude borrowing costs attributable to the construction of qualifying assets, which are assets that take more than six months to prepare for their intended use.

(d) Foreign Currency

Foreign currency transactions are translated into the respective functional currencies of BC Hydro and its subsidiaries, using the exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the reporting date are re-translated to the functional currency at the exchange rate in effect at that date. The foreign currency gains or losses on monetary items is the difference between the amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in the foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

For purposes of consolidation, the assets and liabilities of Powerex, whose functional currency is the US dollar, are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses of Powerex are translated to Canadian dollars at exchange rates at the date of the transactions. Foreign currency differences

resulting from translation of the accounts of Powerex are recognized directly in other comprehensive income and are accumulated in the cumulative translation reserve.

Foreign exchange gains or losses arising from a monetary item receivable from or payable to Powerex, the settlement of which is neither planned nor likely in the foreseeable future and which in substance is considered to form part of a net investment in Powerex by BC Hydro, are recognized directly in other comprehensive income in the cumulative translation reserve.

(e) Property, Plant and Equipment

(i) Recognition and measurement

Property, plant and equipment in service are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labor and any other costs directly attributable to bringing the asset into service. The cost of dismantling and removing an item of property, plant and equipment and restoring the site on which it is located is estimated and capitalized only when, and to the extent that, BC Hydro has a legal or constructive obligation to dismantle and remove such asset. Property, plant and equipment in service include the cost of plant and equipment financed by contributions in aid of construction. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset are capitalized as part of the cost of the qualifying asset. Upon retirement or disposal, any gain or loss is recognized in net income.

Unfinished construction consists of the cost of property, plant and equipment that is under construction or not ready for service. Costs are transferred to property, plant and equipment in service when the constructed asset is capable of operation in the manner intended by management.

(ii) Subsequent costs

The cost of replacing a component of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the component will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced component is derecognized. The costs of property, plant and equipment maintenance are recognized in the profit or loss as incurred.

(iii) Depreciation

Property, plant and equipment in service are depreciated over the expected useful lives of the assets, using the straight-line method. When major components of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

The expected useful lives, in years, of BC Hydro's main classes of property, plant and equipment are:

Generation	15 – 100
Transmission	20 – 65
Distribution	20 – 60
Buildings	5 – 60
Equipment & Other	3 – 35

The expected useful lives and residual values of items of property, plant and equipment are reviewed annually.

Depreciation of an item of property, plant and equipment commences when the asset is available for use and ceases at the earlier of the date the asset is classified as held for sale and the date the asset is derecognized.

(f) Intangible Assets

Intangible assets are recorded at cost less accumulated amortization and accumulated impairment losses. Land rights associated with statutory right of ways acquired from the Province that have indefinite useful lives are not subject to amortization. Intangible assets with finite useful lives are amortized over their expected useful lives on a straight line basis. These assets are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be recoverable. The expected useful lives, in years, are as follows:

Software	2 – 10
Sundry	10 – 20

Amortization of intangible assets commences when the asset is available for use and ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

(g) Asset Impairment

(i) Financial assets

Financial assets, other than those measured at fair value, are assessed at each reporting date to determine whether there is impairment. A financial asset is impaired if evidence indicates that a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its fair value.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income. Any cumulative loss in respect of an available-for-sale financial asset previously recognized in other comprehensive income and presented in unrealized gains/losses on available-for-sale financial assets in equity is transferred to net income.

An impairment loss is reversed if the reversal can be related to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost and available-for-sale financial assets that are debt securities, the reversal is recognized in net income.

(ii) Non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed quarterly to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For intangible assets that have indefinite useful lives, or that are not yet available for use, the recoverable amount is estimated annually.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit, or CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. All of the Company's assets form one CGU for the purposes of testing for impairment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of a CGU are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

Impairment losses recognized in prior periods are assessed at the reporting date for any indications that the loss has decreased or no longer exists. Impairment reversals are recognized immediately in net income when the recoverable amount of an asset increases above the impaired net book value, not to exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss recognized been recognized for the asset in prior years.

(h) Cash and Cash Equivalents

Cash and cash equivalents include unrestricted cash and units of a money market fund that are redeemable on demand and are carried at amortized cost.

(i) Inventories

Inventories are comprised primarily of natural gas, renewable energy certificates and materials and supplies. Inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of inventories comprises all costs of purchase, costs of conversion and other directly attributable costs incurred in bringing the inventories to their present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated selling expenses.

(j) Financial Instruments

(i) Financial Instruments – Recognition and Measurement

All financial instruments are required to be measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on which of the following categories the financial instrument has been classified as: fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities, as defined by the standard. Transaction costs are expensed as incurred for financial instruments classified or designated as fair value through profit or loss. For all other financial instruments, transaction costs are included in the initial carrying amount. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Financial assets and financial liabilities classified as fair value through profit or loss are subsequently measured at fair value with changes in those fair values recognized in net income. Financial assets classified as available-for-sale are subsequently measured at fair value, with changes in those fair values recognized in other comprehensive income until realized. Financial assets classified as held-to-maturity, loans and receivables, and financial liabilities classified as other financial liabilities are subsequently measured at amortized cost using the effective interest method of amortization less any impairment. Derivatives, including embedded derivatives that are not closely related to the host contract and are separately accounted for are generally classified as fair value through profit or loss and recorded at fair value in the consolidated statement of financial position.

The following table presents the classification of financial instruments in the various categories:

Category	Financial Instruments
Financial assets and liabilities at fair value through profit or loss	Temporary investments Designated long-term debt Derivatives not in a hedging relationship
Held to Maturity	US dollar sinking funds
Available for sale financial assets	US dollar sinking funds held in units of a money market fund
Loans and receivables	Cash Accounts receivable and other receivables
Other financial liabilities	Accounts payable and accrued liabilities Revolving borrowings Long-term debt (including current portion due in one year) Finance lease obligations and First Nations liabilities presented in other long-term liabilities

(ii) Fair Value

The fair value of financial instruments reflects changes in the level of commodity market prices, interest rates, foreign exchange rates and credit risk. Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable willing parties who are under no compulsion to act.

Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of future prices and foreign exchange rates, time value of money, counterparty and own credit risk, and volatility. The assumptions used in establishing fair value amounts could differ from actual prices and the impact of such variations could be material. In certain circumstances, Powerex uses valuation inputs that are not based on observable market data and internally developed valuation models which are based on models and techniques generally recognized as standard within the energy industry.

The fair value of financial instruments are classified as Level 1, 2 or 3 as defined below:

Level 1 values are quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.

Level 3 inputs are those that are not based on observable market data.

(iii) Derivative Financial Instruments

The Company uses derivative financial instruments to manage interest rate and foreign exchange risks related to debt and to manage risks related to electricity and natural gas commodity transactions.

Interest rate and foreign exchange related derivative instruments that are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. For liability management activities, the related gains or losses are included in finance charges. For foreign currency exchange risk associated with electricity and natural gas commodity transactions, the related gains or losses are included in domestic revenues. The Company's policy is not to utilize interest rate and foreign exchange related derivative financial instruments for speculative purposes.

Derivative financial instruments are also used by Powerex to manage economic exposure to market risks relating to commodity prices. Derivatives used for energy trading activities that are not designated as hedges are recorded using the mark-to-market method of accounting whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. Gains or losses are included in trade revenues.

(iv) Hedges

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item attributed to the hedged risk, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship, using the effective interest method of amortization.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. When hedge accounting is discontinued the cumulative gain or loss previously recognized in accumulated other comprehensive income remains there until the forecasted transaction occurs. When the hedged item is a non-financial asset or liability, the amount recognized in accumulated other comprehensive income is transferred to the carrying amount of the asset or liability when it is recognized. In other cases the amount recognized in accumulated other comprehensive income is transferred to net income in the same period that the hedged item affects net income.

Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, the hedging relationship is discontinued, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

(k) Investments Held in Sinking Funds

Investments held in sinking funds are held as individual portfolios and are classified as held to maturity. Securities included in an individual portfolio are recorded at cost, adjusted by amortization of any discounts or premiums arising on purchase, on a yield basis over the estimated term to settlement of the security. Realized gains and losses are included in net income.

(l) Deferred Revenue

Deferred revenue consists principally of amounts received under the agreement relating to the Skagit River, Ross Lake and the Seven Mile Reservoir on the Pend d'Oreille River (collectively, "the Skagit River Agreement") and amounts received under contributions in aid of construction.

Under the Skagit River Agreement, BC Hydro has committed to deliver a predetermined amount of electricity each year to the City of Seattle for an 80-year period ending in fiscal 2066 in return for two annual payments of approximately US$22 million per year for a 35 years ending in 2021 and US$100,000 (adjusted for inflation) per year for the 80-year period ending in 2066. The amounts received under the agreement are deferred and included in income on an annuity basis over the electricity delivery period ending in fiscal 2066.

(m) Contributions In Aid of Construction

Contributions in aid of construction are amounts paid by customers toward the cost of property, plant and equipment required for the extension of services to supply electricity. These amounts are recognized into revenue over the expected useful life of the related assets, as the associated contracts do not have a finite period over which service is provided.

(n) Post Employment Benefits

The cost of pensions and other post employment benefits earned by employees is actuarially determined using the projected accrued benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The expected long-term rate of return on plan assets is used to calculate the income on plan assets. The obligations are discounted using a market interest rate at the end of the year on high-quality corporate debt instruments that match the timing and amount of expected benefit payments.

Past service costs are recognized as an expense on a straight-line basis over the average period until the benefits become vested. If the benefits have already vested, immediately following the introduction of, or changes to, a defined benefit plan, past service costs are recognized in earnings immediately.

A plan curtailment will result if the Company has demonstrably committed to a significant reduction in the expected future service of active employees or a significant element of future service by active employees no longer qualifies for benefits. A curtailment is recognized when the event giving rise to the curtailment occurs.

The expected return on plan assets and the interest cost on the defined benefit plan liabilities arising from the passage of time are included in finance income and finance costs, respectively. The Company recognizes expenses related to the defined benefit plan in personnel expenses and recognizes actuarial gains and losses immediately in other comprehensive income. The amount recognized in other comprehensive income is subsequently transferred to a regulatory asset account for inclusion in future rates.

(o) Provisions

A provision is recognized if the Company has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate of the obligation can be determined. For obligations of a long-term nature, provisions are measured at their present value by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability except in cases where future cash flows have been adjusted for risk.

Asset Retirement Obligations

Asset retirement obligations (AROs) are legal and constructive obligations associated with the retirement of long-lived assets. A liability is recorded at the present value of the estimated future costs based on management's best estimate. When a liability is initially recorded, the Company capitalizes the costs by increasing the carrying value of the asset. The increase in net present value of the provision for the expected cost is included in finance costs as accretion (interest) expense. Adjustments to the provision made for changes in timing, amount of cash flows and discount rates are capitalized and amortized over the useful life of the associated asset. Actual costs incurred upon settlement of an asset retirement obligation are charged against the related liability. Any difference between the actual costs incurred upon settlement of the asset retirement obligation and the recorded liability is recognized in net income at that time.

Environmental Expenditures and Liabilities

Environmental expenditures are expensed as part of operating activities, unless they constitute an asset improvement or act to mitigate or prevent possible future contamination, in which case the expenditures are capitalized and amortized to income. Environmental liabilities arising from a past event are accrued when it is probable that a present legal or constructive obligation will require the Company to incur environmental expenditures.

First Nations

The Company is subject to existing and pending legal claims relating to alleged infringement and damages in the operation and use of facilities on property where ownership is claimed by various First Nations groups. These claims may be resolved unfavourably with respect to the Company and may have a significant adverse effect on the Company's financial position. For existing claims where settlement agreements have advanced to the extent that probable settlement amounts can reasonably be predicted, management has recorded a provision for the potential costs of those settlements.

Legal

The Company is currently defending certain lawsuits where the final outcome and costs are not able to be determined as at period end. Management obtains the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with lawsuits. Further information regarding lawsuits in progress is disclosed in Note 14, Commitments and Contingencies.

(p) Leases

Embedded Leases

The Company may enter into an arrangement that does not take the legal form of a lease but conveys a right to use an asset in return for a payment or series of payments. Arrangements in which a party conveys a right to the Company to use an asset may in substance be, or contain, leases that should be accounted for as either a finance or operating lease. Determining whether an arrangement is, or contains, a lease requires an assessment of whether fulfilment of the arrangement is dependent on the use of a specific asset and whether the arrangement conveys a right to use the asset. The right to use an asset is conveyed if the right to operate or control physical access to the underlying asset is provided or if the Company consumes substantially all of the output of the asset and the price paid for the output is neither contractually fixed per unit of output nor equal to the current market price.

Finance Leases

Leases where substantially all of the benefits and risk of ownership rest with the Company are accounted for as finance leases. Finance leases are recognized as assets and liabilities at the lower of the fair value of the asset and the present value of the minimum lease payments at the date of acquisition. Finance costs represent the difference between the total leasing commitments and the fair value of the assets acquired. Finance costs are charged to net income over the term of the lease at interest rates applicable to the lease on the remaining balance of the obligations. Assets under finance leases are depreciated on the same basis as property, plant and equipment or over the term of the relevant lease, whichever is shorter.

Operating Leases

Leases where substantially all of the benefits and risk of ownership remain with the lessor are accounted for as operating leases. Rental payments under operating leases are expensed to net income on a straight-line basis over the term of the relevant lease. Benefits received and receivable as an incentive to enter into an operating lease are recognized as an integral part of the total lease expense and are recorded on a straight-line basis over the term of the lease.

(q) Taxes

BC Hydro pays local government taxes and grants in lieu to municipalities and regional districts. As a Crown corporation, BC Hydro is exempt from Canadian federal and provincial income taxes.

(r) New Standards and Interpretations Not Yet Adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the period ended June 30, 2012, and have not been applied in preparing these condensed consolidated interim financial statements. In particular, the following new and amended standards become effective for BC Hydro's annual periods beginning on or after the dates noted below:

- IFRS 9, *Financial Instruments* (effective April 1, 2015)
- IFRS 10, *Consolidated Financial Statements* (effective April 1, 2013)
- IFRS 11, *Joint Arrangements* (effective April 1, 2013)
- IFRS 12, *Disclosure of Interests in Other Entities* (effective April 1, 2013)
- IFRS 13, *Fair Value Measurement* (effective April 1, 2013)
- Amendments to IAS 1, *Presentation of Financial Statements* (effective April 1, 2013)
- Amendments to IAS 19, *Employee Benefits* (effective April 1, 2013)
- IAS 28, *Investments in Associates and Joint Ventures* (effective April 1, 2013)
- Amendments to IAS 32 and IFRS 7, *Offseting Financial Assets and Liabilities* (effective April 1, 2014 and April 1, 2013, respectively)

BC Hydro does not have any plans to early adopt any of the new or amended standards. The extent of the impact on adoption of these standards is not known at this time.

NOTE 4: OPERATING EXPENSES

	For the three months ended June 30	
(in millions)	2012	2011
Electricity and gas purchases	$ 265	$ 323
Water rentals	74	71
Transmission charges	32	30
Personnel expenses	137	138
Materials and external services	145	144
Amortization and depreciation (Note 6)	230	198
Grants and taxes	48	46
Capitalized costs	(62)	(65)
Other costs / (recoveries)	5	(6)
Total	$ 874	$ 879

NOTE 5: FINANCE CHARGES

(in millions)	*For the three months ended June 30* 2012	2011
Interest on long-term debt	$ 157	$ 150
Interest on finance lease liabilities	7	6
Net interest on defined benefit plan obligations	49	47
Less: Capitalized interest	(18)	(13)
Total finance costs	195	190
Expected return on defined benefit plan assets	(46)	(44)
Other recoveries	(18)	(20)
Total	$ 131	$ 126

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended June 30* 2012	2011
Depreciation of property, plant and equipment	$ 140	$ 127
Amortization of intangible assets	14	13
Amortization of regulatory accounts and other	76	58
Total	$ 230	$ 198

NOTE 7: INVENTORIES

During the three month period ended June 30, 2012, an impairment recovery of $8 million (2011 – impairment of $1 million) was recorded in electricity and gas purchases to adjust the cost of natural gas in storage to its net realizable value as a result of increases in market prices. At June 30, 2012, $53 million (2011 - $58 million) of the carrying value of natural gas in storage was valued at net realizable value.

NOTE 8: PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment and intangible asset expenditures for the three months ended June 30, 2012 were $435 million (2011 - $354 million).

BC Hydro is forecasting to spend $2,361 million on property, plant and equipment and intangibles in fiscal 2013.

NOTE 9: RATE REGULATION

REGULATORY ACCOUNTS

The following regulatory assets and liabilities have been established through rate regulation. For the period ended June 30, 2012, the impact of regulatory accounting has resulted in an increase to net income of $57 million (2011- $25 million).

(in millions)	*March 31 2012 CGAAP*	*Transition to Prescribed Standards (Note 16)*	*April 1 2012*	*Addition (Reduction)*	*Amortization*	*Net Change*	*June 30 2012*
Regulatory Assets							
Heritage Deferral Account	$ 244	$ -	$ 244	$ (33)	$ (13)	$ (46)	$ 198
Non-Heritage Deferral Account	367	62	429	37	(19)	18	447
Trade Income Deferral Account	175	30	205	-	(9)	(9)	196
Demand-Side Management Programs	646	(8)	638	28	(13)	15	653
First Nation Negotiations, Litigation & Settlement Costs	543	-	543	5	(2)	3	546
Non-Current Pension Cost	55	322	377	(2)	(4)	(6)	371
Site C	181	-	181	17	-	17	198
CIA Amortization Variance	68	-	68	1	-	1	69
Environmental Provisions	234	88	322	26	-	26	348
Smart Metering and Infrastructure	92	-	92	20	-	20	112
Finance Charges	6	43	49	(6)	-	(6)	43
IFRS Pension & Other Post Employment Benefits	-	762	762	-	(10)	(10)	752
IFRS Property, Plant and Equipment	-	254	254	49	(1)	48	302
Other Regulatory Accounts	150	-	150	-	(7)	(7)	143
Total Regulatory Assets	2,761	1,553	4,314	142	(78)	64	4,378
Regulatory Liabilities							
Future Removal and Site Restoration Costs	120	(16)	104	-	(4)	(4)	100
Rate Smoothing	70	-	70	9	-	9	79
Foreign Exchange Gains and Losses	103	-	103	(3)	-	(3)	100
Other Regulatory Accounts	2	-	2	5	-	5	7
Total Regulatory Liabilities	295	(16)	279	11	(4)	7	286
Net Regulatory Asset	$ 2,466	$ 1,569	$ 4,035	$ 131	$ (74)	$ 57	$ 4,092

OTHER REGULATORY ACCOUNTS

Other regulatory asset accounts with individual balances less than $65 million include the following: Arrow Water Systems Divestiture, Capital Project Investigation Costs, Home Purchase Option Program, Return on Equity (ROE) Adjustment, and Waneta Rate Smoothing.

NOTE 10: LONG-TERM DEBT AND DEBT MANAGEMENT

BC Hydro's long-term debt comprises bonds and debentures and revolving borrowings obtained under an agreement with the Province.

In the three month period ended June 30, 2012, BC Hydro issued bonds with a par value of $578 million (June 30, 2011 – $1 billion), a weighted average effective interest rate of 3.4 per cent (June 30, 2011 – 4.4 per cent) and a weighted average term to maturity of 26.1 years (June 30, 2011 – 31.1 years).

NOTE 11: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

BC Hydro monitors its capital structure on the basis of its debt to equity ratio. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive income (loss) and contributed surplus.

During the period, there were no changes in this approach to capital management.

The debt to equity ratio at June 30, 2012, March 31, 2012 and April 1, 2011 was as follows:

(in millions)	As at June 30 2012	As at March 31 2012	As at April 1 2011
Total debt, net of sinking funds	$ 13,436	$ 12,845	$ 11,615
Less: Cash and cash equivalents	(7)	(12)	(27)
Net Debt	$ 13,429	$ 12,833	$ 11,588
Retained earnings	$ 3,128	$ 3,075	$ 2,747
Contributed surplus	60	60	60
Accumulated other comprehensive income	76	84	74
Total Equity	$ 3,264	$ 3,219	$ 2,881
Net Debt to Equity Ratio	80 : 20	80 : 20	80 : 20

PAYMENT TO THE PROVINCE

BC Hydro is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No Payment has been accrued as at June 30, 2012 (March 31, 2012 - $230 million; April 1, 2011 - $463 million, included in accounts payable and accrued liabilities), as BC Hydro's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

NOTE 12: POST EMPLOYMENT BENEFITS

The expense recognized in the statement of comprehensive income for the Company's benefit plans for the three months ended June 30, 2012 was $23 million (2011 - $23 million).

The Company's contribution to its funded defined benefit plan for the three months ended June 30, 2012 was $12 million (2011 - $12 million).

NOTE 13: OTHER LONG-TERM LIABILITIES

(in millions)	June 30 2012	March 31 2012	April 1 2011
Provisions			
Environmental liabilties	$ 305	$ 301	$ 259
Asset retirement obligations	95	94	74
Other	3	3	3
Total Provisions	403	398	336
First Nations liabilities	388	393	303
Finance lease obligations	305	309	324
Deferred revenue	411	418	412
	1,507	1,518	1,375
Less: Current portion, included in accounts payable and accrued liabilities	(73)	(97)	(114)
Total	$ 1,434	$ 1,421	$ 1,261

NOTE 14: COMMITMENTS AND CONTINGENCIES

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At June 30, 2012, Powerex was owed US $265 million (CDN $270 million) plus interest by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties. It is expected that the receivables owed to Powerex will be offset against the market-wide refund amount that Powerex is required to pay.

The Company has elected not to report information regarding provisions as this information could prejudice the Company's position in ongoing litigation.

NOTE 15: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statement of comprehensive income is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on the Company's operating results.

NOTE 16: EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

As stated in Note 2, these are the Company's first condensed consolidated interim financial statements prepared in accordance with the Prescribed Standards.

The accounting policies set out in Note 3 have been applied in preparing the condensed consolidated interim financial statements for the three months ended June 30, 2012, the comparative information presented in these interim financial statements for both the three months ended June 30, 2011 and the year ended March 31, 2012 and in the preparation of an opening statement of financial position at April 1, 2011 (the Company's date of transition).

In adopting the Prescribed Standards, the Company has applied the recognition, measurement, presentation and disclosure principles of IFRS 1 in preparing its transitional adjustments and financial statements. The principles of IFRS 1 generally require that first-time adopters of a new set of accounting policies retrospectively apply all effective standards and interpretations in effect as at the reporting date. However, IFRS 1 also provides for certain optional exemptions and certain mandatory exemptions to full retrospective application. In adopting the Prescribed Standards, the Company has elected to apply the following mandatory and optional exemptions available under IFRS 1:

(a) IFRS Mandatory Exceptions

(i) Hedge Accounting

Hedging relationships that do not qualify for hedge accounting in accordance with IAS 39, *Financial Instruments: Recognition and Measurement* are not reflected in the opening statement of financial position. Hedge accounting has therefore been discontinued for those transactions that no longer meet the conditions under IAS 39 on a prospective basis. No transactions entered into before the date of transition to the Prescribed Standards have been retrospectively designated as hedges.

(ii) Estimates

The Company's estimates under the Prescribed Standards at the date of transition were consistent with estimates made under CGAAP. Estimates previously made were not revised for changes under the Prescribed Standards except to reflect any difference in accounting policies.

(b) IFRS Optional Exemptions

(i) Fair Value as Deemed Cost

Entities that hold items of property, plant and equipment or intangible assets used in operations subject to rate regulation are permitted under IFRS 1 to elect to use their carrying amounts as deemed cost at the date of transition to the Prescribed Standards. The carrying amount of such items may include amounts that were recorded under CGAAP but do not qualify for capitalization in accordance with IFRS. The Company has elected to apply this exemption except for assets impacted by elections (ii) and (vi) in this section.

(ii) Leases

IFRS 1 allows entities to apply the transitional provisions in IFRIC 4, *Determining Whether an Arrangement Contains a Lease*, which allows the Company to determine whether an arrangement existing at the date of transition to the Prescribed Standards contains a lease on the basis of facts and circumstances existing at that date. This election has been applied to the assessment of energy purchase contracts that were previously grandfathered under EIC 150, *Determining Whether an Arrangement Contains a Lease*.

(iii) Employee Benefits

IFRS 1 allows entities to recognize all cumulative unrecognized actuarial gains and losses at the date of transition to the Prescribed Standards. This election has been applied to all employee benefit plans.

(iv) Cumulative Translation Differences

IAS 21, *The Effects of Changes in Foreign Exchange Rates* requires an entity to recognize foreign exchange differences arising on translation of subsidiaries with a different functional currency in other comprehensive income and accumulate these in a separate component of equity. However, IFRS 1 allows entities to not comply with these requirements for cumulative translation differences that existed at the date of transition to the Prescribed Standards. This election has been applied to the operations of Powerex with all related cumulative translation differences deemed to be zero at the date of transition.

(v) Designation of Previously Recognized Financial Instruments

IFRS 1 permits an entity to designate a previously recognized financial liability as a financial liability at fair value through profit or loss. The Company has discontinued fair value hedge accounting with respect to a number of its Canadian dollar denominated debt issues and has applied this exemption to the underlying debt under the discontinued hedging relationship.

(vi) Decommissioning Liabilities Included In the Cost of Property, Plant and Equipment

IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities* requires specified changes in a decommissioning, restoration or similar liability to be adjusted against the cost of the asset to which it relates with the adjusted amount depreciated prospectively over its remaining useful life. IFRS 1 provides an exemption from complying with these requirements for changes in such liabilities that occurred before the date of transition to the Prescribed Standards. The Company has applied this exemption to existing asset retirement obligations recognized under CGAAP and to new obligations recognized on transition to the Prescribed Standards.

(vii) Fair Value Measurement of Financial Assets or Financial Liabilities at Initial Recognition

For transactions which are recognized as financial instruments at fair value under IFRS, but were not recognized at fair value under CGAAP, IFRS 1 permits an entity to avoid retrospectively applying certain measurement guidance in IAS 39 for the term of the transaction prior to IFRS transition. This exemption is only available for transactions which were entered into prior to the date of IFRS transition. The Company has applied this exemption to all eligible transactions as at the date of transition.

In preparing its opening statement of financial position, BC Hydro has adjusted amounts reported previously in financial statements prepared in accordance with CGAAP. An explanation of how the transition from CGAAP to the Prescribed Standards has affected BC Hydro's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables:

Reconciliation of the Consolidated Statement of Financial Position Prepared According to the Prescribed Standards

		April 1, 2011			June 30, 2011			March 31, 2012		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards	Canadian GAAP	Effect of Transition	Prescribed Standards	Canadian GAAP	Effect of Transition	Prescribed Standards
ASSETS										
Current Assets										
Cash and cash equivalents		$ 27	$ -	$ 27	$ 7	$ -	$ 7	$ 12	$ -	$ 12
Accounts receivable and accrued revenue		569	-	569	568	-	568	595	-	595
Inventories	r	128	(2)	126	151	(2)	149	142	-	142
Prepaid expenses		156	-	156	196	-	196	147	-	147
Current portion of derivative financial instrument assets	n	198	-	198	157	1	158	140	-	140
		1,078	(2)	1,076	1,079	(1)	1,078	1,036	-	1,036
Non-Current Assets										
Property, plant and equipment	a-e,g,o	15,211	(192)	15,019	15,436	(249)	15,187	16,420	(429)	15,991
Intangible assets		335	-	335	349	-	349	412	-	412
Regulatory assets (Note 9)	t	2,436	983	3,419	2,465	1,032	3,497	2,761	1,553	4,314
Investments held in sinking funds		97	-	97	97	-	97	105	-	105
Employee future benefits	h	296	(296)	-	286	(286)	-	272	(272)	-
Derivative financial instrument assets	n	26	1	27	21	1	22	41	1	42
		18,401	496	18,897	18,654	498	19,152	20,011	853	20,864
		$ 19,479	$ 494	19,973	$ 19,733	$ 497	$ 20,230	$ 21,047	$ 853	$ 21,900
LIABILITIES AND EQUITY										
Current Liabilities										
Accounts payable and accrued liabilities	n,o	$ 1,605	$ 5	$ 1,610	$ 1,042	$ 11	$ 1,053	$ 1,417	$ 14	$ 1,431
Current portion of long-term debt	j	2,793	10	2,803	2,573	10	2,583	2,886	10	2,896
Current portion of derivative financial instrument liabilities	n	159	6	165	123	1	124	116	7	123
		4,557	21	4,578	3,738	22	3,760	4,419	31	4,450
Non-Current Liabilities										
Long-term debt	j,l	8,851	58	8,909	9,819	52	9,871	10,026	28	10,054
Regulatory liabilities (Note 9)	t	276	(1)	275	280	(1)	279	295	(16)	279
Derivative financial instrument liabilities	n	212	-	212	213	-	213	189	-	189
Contibutions in aid	c	1,012	-	1,012	1,032	(1)	1,031	1,110	(4)	1,106
Post employment benefits	h	345	500	845	351	501	852	370	812	1,182
Other long-term liabilities	f-g,o,r	1,346	(85)	1,261	1,331	(74)	1,257	1,440	(19)	1,421
		12,042	472	12,514	13,026	477	13,503	13,430	801	14,231
Shareholder's Equity										
Contributed surplus	l	60	-	60	60	-	60	60	-	60
Retained earnings	b-h,j-o,r	2,747	-	2,747	2,839	-	2,839	3,075	-	3,075
Accumulated other comprehensive income	h,k,m,r	73	1	74	70	(2)	68	63	21	84
		2,880	1	2,881	2,969	(2)	2,967	3,198	21	3,219
		$ 19,479	$ 494	$ 19,973	$ 19,733	$ 497	$ 20,230	$ 21,047	$ 853	$ 21,900

For presentation purposes, the current portion of other long-term liabilities has been reclassified and included in accounts payable and accrued liabilities in the comparative periods under CGAAP, increasing accounts payable and accrued liabilities and decreasing other long-term liabilities by $90 million at April 1, 2011, $97 million at June 30, 2011 and $73 million at March 31, 2012.

Reconciliation of Consolidated Statement of Comprehensive Income

		For the three months ended June 30, 2011			For the year ended March 31, 2012		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards	Canadian GAAP	Effect of Transition	Prescribed Standards
Revenues							
Domestic	c,n,p	$ 886	$ 10	$ 896	$ 3,709	$ 39	$ 3,748
Trade	t	195	6	201	975	-	975
		1,081	16	1,097	4,684	39	4,723
Expenses							
Operating expenses (Note 4)	b-d,f-i,o-q	866	13	879	3,643	23	3,666
Finance charges (Note 5)	e,f,i-m,o,q	123	3	126	483	16	499
Net Income		$ 92	$ -	$ 92	$ 558	$ -	$ 558
Other Comprehensive Income (Loss):							
Effective portion of changes in fair value on derivatives designated as cash flow hedges	k,m	$ (11)	$ -	$ (11)	$ 16	$ (9)	$ 7
Reclassification to income of gain (loss) on derivatives designated as cash flow hedges	m	8	-	8	(26)	14	(12)
Foreign currency translation gains (losses)	r	-	(3)	(3)	-	15	15
Other Comprehensive Income (Loss)		$ (3)	$ (3)	$ (6)	$ (10)	$ 20	$ 10
Total Comprehensive Income		$ 89	$ (3)	$ 86	$ 548	$ 20	$ 568

NOTES TO THE RECONCILIATION OF THE CONSOLIDATED STATEMENT OF FINANCIAL POSITION AND CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME PREPARED ACCORDING TO THE PRESCRIBED STANDARDS:

The following explanations disclose the key impacts arising on transition from CGAAP to the Prescribed Standards. The net transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income as at April 1, 2011 and for the year ended March 31, 2012 have been deferred to regulatory assets and liabilities on the statement of financial position for regulatory accounting purposes. As identified in BC Hydro's Amended fiscal 2012-2014 Revenue Requirements Application (Amended RRA), BC Hydro will request approval to defer IFRS retained earnings impacts that are not within the current scope of existing regulatory deferral accounts. Refer to Regulatory Note 9 for further information on regulatory accounts.

(a) Fair Value as Deemed Cost

With the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases and asset retirement obligation assets.

(b) Componentization

CGAAP permits component accounting for property, plant and equipment but does not require componentization of assets. IFRS requires the componentization of significant parts of an asset where the useful life or the depreciation method of the part of the asset differs from the remainder of the asset. In addition, certain expenditures under CGAAP are eligible for capitalization and are considered asset components under IFRS. The impact of componentization under IFRS as at and for the three months ended June 30, 2011 and the year ended March 31, 2012 was a decrease in property, plant and equipment of $2 million and $7 million, respectively and a corresponding increase in depreciation expense of $2 million and $7 million, respectively due to the reduction in the useful life of the component assets compared to the life of the parent asset.

(c) Mass Asset Retirements

Under CGAAP, the Company did not record any gains or losses for assets that are tracked on a pooled basis except when entire pools or a substantial portion of an asset pool is retired prior to being fully amortized. IFRS requires that gains and losses on disposal of assets be recognized immediately in income, and not charged or credited to accumulated amortization. The impact of the IFRS requirement for the three months ended June 30, 2011 and the year ended March 31, 2012 were losses of $7 million and $29 million, respectively, recognized for the retirement of pooled assets offset by recognition of associated deferred contributions in aid into revenue in the amount $1 million and $4 million, respectively.

(d) Capital Overhead

Under CGAAP, there are expenditures allocated to capital that are associated with capital programs that are no longer eligible for capitalization under IFRS as they are not considered directly attributable to the construction of the asset. The effect of this difference as at and for the three months ended June 30, 2011 and the year ended March 31, 2012 was a decrease in property, plant and equipment and a corresponding increase in operating costs in the amount of $52 million and $206 million, respectively.

(e) Interest During Construction

Under CGAAP, the Company capitalized interest on all capital projects regardless of project duration period. Under IFRS, interest costs are only capitalized in relation to an asset that takes a "substantial period of time" to prepare for their intended use. The Company considers a substantial period of time to be in excess of six months; therefore interest costs that relate to capital projects with less than six months duration to prepare for their intended use are no longer eligible for capitalization and must be expensed in the period incurred. The effect as at and for the three months ended June 30, 2011 and the year ended March 31, 2012 was a decrease in property, plant and equipment and a corresponding increase in finance charges of $1 million and $7 million, respectively.

(f) New Provisions

Measurement requirements for provisions under IFRS have a lower recognition threshold than CGAAP and as a result, upon transition to the Prescribed Standards, an ARO has been estimated in connection with asbestos at various facilities. This resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. The accretion adjustment for the three months ended June 30, 2011 and the year ended March 31, 2012 was an increase of $0.3 million and $1 million, respectively in finance charges and a corresponding increase to the environmental liability.

A provision has also been estimated in connection with the decommissioning of a specific facility due to the identification of a constructive obligation under IFRS. The amount recognized as at and for the year ended March 31, 2012 was a $15 million environmental obligation offset by a corresponding increase in provision expense.

(g) Provision Re-Measurement

Under CGAAP, there was no requirement to re-measure provisions for changes in discount rates. Under IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including a reassessment in discount rates where the present value of a provision has been calculated. Upon transition to the Prescribed Standards, the revaluation of these provisions to reflect the appropriate discount rates at the end of each reporting period resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. There was an increase in provisions and provision expense for the three months ended June 30, 2011 and the year ended March 31, 2012 of $7 million and $42 million, respectively.

The Company elected to use an exemption allowing ARO related assets to be re-measured on a simplified approach at the transition date rather than perform full detailed ARO calculations. At the transition date, the re-measurement increased

ARO liabilities by $6 million, increased property, plant and equipment by $4 million and decreased retained earnings by $2 million. In addition to the transition date adjustment, the re-measurement increased the ARO liabilities and property, plant and equipment by $2 million and $1 million, respectively for the three months ended June 30, 2011 and March 31, 2012.

(h) Actuarial Gains and Losses Recognition

Under CGAAP, the Company recognized actuarial gains and losses in net income over the employees' remaining service period. Under IFRS, the Company's policy is to recognize all actuarial gains and losses in other comprehensive income. As permitted by IFRS 1, the Company has elected to recognize all previously unrecognized actuarial gains and losses that existed at the date of transition in opening retained earnings for all of its employee post-employment and defined benefit plans. IAS 39 requires all vested past service costs to be recognized immediately. Under CGAAP, the Company recognized past service costs over the expected average remaining service life of the employees. On the date of transition, the Company recognized all vested past service costs into opening retained earnings with a resulting decrease in the post retirement benefit liability.

The effect as at the date of the transition resulted in a decrease to the defined benefit asset of $296 million, an increase in the defined benefit obligation of $500 million and a decrease in opening retained earnings of $796 million. The reversal of amortization previously recognized under CGAAP resulted in a decrease of $9 million and $34 million, respectively to the pension benefit obligation and expense for three months ended June 30, 2011 and the year ended March 31, 2012. For the year ended March 31, 2012, actuarial gains and losses recognized in other comprehensive income amounted to a loss of $322 million.

In accordance with the Prescribed Standards, these impacts have been deferred to the Non-Current Pension Cost regulatory account.

(i) Interest Reclassification

Under IFRS, interest on defined benefit obligations and interest on defined benefit plan assets are classified as finance charges rather than as operating costs under CGAAP. The effect was a reclassification of net interest expense on the plan obligations and assets from operating costs to finance charges of $3 million and $13 million, respectively for the three months ended June 30, 2011 and the year ended March 31, 2012.

(j) Designation of Previously Recognized Financial Instruments

As permitted by IFRS 1, the Company has elected to designate a number of previously recognized liabilities as a financial liability at fair value through the profit or loss at the date of transition. The Company has discontinued fair value hedge accounting with respect to a number of its Canadian denominated debt issues and has applied this exemption to the underlying debt under the discontinued hedging relationship. This increased the current portion of long term debt by $10 million, increased long term debt by $53 million and decreased opening retained earnings by $63 million as at April 1, 2011. There was an additional decrease in long-term debt of $6 million and $28 million, respectively and a corresponding decrease in finance charges for the three months ended June 30, 2011 and the year ended March 31, 2012.

The carrying value of these debt issues at March 31, 2011 was $1,225 million and the fair value at April 1, 2011, the date of transition, was $1,288 million.

(k) Ineffectiveness On Cash Flow Hedges

Certain methods to assess hedge effectiveness under CGAAP are no longer permitted under IFRS. The resulting transitional adjustment recorded to reflect the hedge ineffectiveness that would have been realized under IFRS in prior years as at the date of transition and the three months ended June 30, 2011 was less than $1 million.

(l) Fair Value of Debt Issuance

Certain previous Canadian debt issues were issued to the Province of BC at yields that were higher or lower than market yields (off market rates). This was allowed under CGAAP under the related parties guidance. IFRS requires all debt to be recorded at its fair value at inception. This adjustment is required to reflect the accounting standards under IFRS for off market debt issues. This transitional adjustment results in an increase to debt of $5 million, an increase to contributed surplus of $11 million, and a decrease to retained earnings of $16 million as at April 1, 2011.The amortization of this transitional adjustment for the three months ended June 30, 2011 and year ended March 31, 2012 resulted in a decrease to finance charges and long-term debt of $0.4 million and $2 million.

(m) De-Designation of Cash Flow Hedging Relationship as at April 1, 2011

This transitional adjustment reverses the mark-to-market adjustment from other comprehensive income to finance charges for the comparative period due to the de-designation of specific hedges. The effect is an increase in other comprehensive income and finance charges for the three months ended June 30, 2011 and year ended March 31, 2012 of $1 million and $3 million.

There was an additional adjustment recorded for the amortization of accumulated other comprehensive income amounts due to the de-designation of hedge accounting on April 1, 2011 for IFRS transition. The transitional adjustment resulted in an increase in finance charges and accumulated other comprehensive income for the three months ended June 30, 2011 and the year ended March 31, 2012 of $0.5 million and $2 million.

(n) New Derivatives

Under IFRS, the lack of a specified notional quantity does not preclude a contract from meeting the criteria for classification as a derivative financial instrument, as is the case under CGAAP. As a result, on transition to the Prescribed Standards, a number of transactions previously recognized by the Company as an executor contract under CGAAP are now recognized on a fair value basis under IFRS. The impact on the date of transition was a decrease of $3 million to retained earnings offset by an increase for both derivative financial instrument assets and liabilities of $1 million and $6 million, respectively and a decrease in accounts payable and accrued liabilities of $2 million.

There was a further increase in derivative financial instrument assets of $1 million and a decrease of $5 million in derivative financial instrument liabilities offset by an increase in revenue of $6 million for the three months ended June 30, 2011, and a decrease of $1 million in derivative financial instrument assets and an increase of $2 million and a $1 million in accounts payable and accrued liabilities and derivative financial instrument liabilities respectively, offset by a decrease in revenue for the year ended March 31, 2012.

(o) Leases

On the date of transition to the Prescribed Standards, an energy purchase agreement was assessed as containing an embedded lease under IFRIC 4. The arrangement was subsequently assessed under IAS 17, *Leases* and was classified as a finance lease. Adjustments were also made to two energy purchase agreements that were classified as finance leases under CGAAP. One agreement was reclassified from a finance lease to an operating lease under IFRS. Another agreement was re-measured using the interest rate implicit in the agreement.

The following table summarizes the impact of the adjustments:

	Incremental Increase (Decrease)		
(in millions)	As at April 1, 2011	For the three months ended June 30, 2011	For the year ended March 31, 2012
Property, plant and equipment	$ (196)	$ 3	$ 11
Lease obligation liability	(137)	2	8
Accounts payable and accrued liabilities	-	6	6
Retained earnings	(59)	-	-
Finance charges	-	1	6
Operating costs	-	4	(3)

(p) Contributions in Aid

Contributions that are received by the Company to fund customer connections to the ongoing supply of electricity will continue to be recorded as deferred revenue under IFRS; however, amortization of the deferred revenue will be recorded as revenue, rather than as depreciation expense. The effect for the three months ended June 30, 2011 and the year ended March 31, 2012 was a reclassification from depreciation expense to revenue of $10 million and $39 million, respectively.

(q) Accretion expense reclassification

Under IFRS, accretion expense is classified as finance charges rather than as operating costs under CGAAP. The reclassification adjustment from operating costs to finance charges was $0.5 million and $2 million for the three months ended June 30, 2011 and the year ended March 31, 2012, respectively.

(r) Functional Currency

In accordance with IFRS 1, the Company elected to deem all foreign currency translation differences arising on consolidation of Powerex to be nil at the date of transition, April 1, 2011. The foreign currency translation adjustment was a loss of $3 million and a gain of $15 million, recognized in other comprehensive income for the three months ended June 30, 2011 and the year ended March 31, 2012, respectively. The impact of foreign currency translation on consolidation is not deferred for regulatory purposes.

In addition, as a result of the change in Powerex's functional currency, Powerex recorded adjustments to its foreign exchange gains and losses as at April 1, 2011 and for the three months ended June 30, 2011 and the year ended March 31, 2012. The impact of these adjustments was to decrease retained earnings by $3 million at April 1, 2011 and to record a foreign exchange gain of $3 million and a foreign exchange loss of $14 million for the three months ended June 30, 2011 and the year ended March 31, 2012, respectively. The impact of these differences has been deferred for regulatory purposes in the Trade Income Deferral Account.

(c) Change in Classification of Cash Flows

The following table is a reconciliation of the change in classification of cash flows arising from the transition to IFRS for the three months ended June 30, 2011:

(in millions)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Net cash used in operating activities	$ 68	$ 15	$ 83
Net cash provided by financing activities	293	-	293
Net cash provided by investing activities	(381)	(15)	$ (396)

The adjustments to the cash flow classification arise as a result of the presentation of the Company's contributions in aid of construction and an adjustment to remove capitalized interest from property, plant and equipment expenditures, which were reclassified from investing activities to operating activities.

(d) Deferral of IFRS Transitional Impacts

The IFRS transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income have been deferred for regulatory purposes. The changes have increased (decreased) regulatory assets and liabilities as follows:

(in millions)		Incremental Increase (Decrease)		
	Note	As at April 1, 2011	For the three months ended June 30, 2011	For the year ended March 31, 2012
Componentization	b	$ -	$ 2	$ 7
Mass Asset Retirements	c	-	6	25
Capital Overhead	d	-	52	206
Interest During Construction	e	-	1	7
New Provisions	f	26	-	16
Provision Re-Measurement	g	28	7	42
Actuarial Gains and Losses Recognition	h	796	(9)	288
Designation of Previously Recognized Financial Instruments	j	63	(6)	(28)
Ineffectiveness of Cash Flow Hedges	k	1	(1)	-
Fair Value of Debt Issuance	l	5	-	(2)
De-Designation of Cash Flow Hedging Relationship	m	-	1	3
New Derivatives	n	3	(6)	4
Leases	o	59	5	3
Foreign Exchange	r	3	(3)	14
Incremental increase for the period		984	49	585
Cumulative increase as at the balance date		$ 984	$ 1,033	$ 1,569
Regulatory assets		$ 983	$ 1,032	$ 1,553
Regulatory liabilities		(1)	(1)	(16)
Net regulatory increase		$ 984	$ 1,033	$ 1,569